"IMPACTS OF INTERMITTENT RENEWABLE GENERATION ON ELECTRICITY SYSTEM COSTS"

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Abstract

A successful deployment of power generation coming from variable renewable sources, such as wind and solar photovoltaic, strongly depends on the economic cost of system integration. This paper, in seeking to look beyond the impact of renewable generation on the evolution of the total economic costs associated with the operation of the electricity system, aims to estimate the sensitivity of balancing market requirements and costs to the variable and non-fully predictable nature of intermittent renewable generation. The estimations reported in this paper for the Spanish electricity system stress the importance of both attributes as well as power system flexibility when accounting for the cost of balancing services.

Keywords: electricity market design; balancing services; renewable energy; variable and intermittent generation; system flexibility

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1. INTRODUCTION

In recent years, there has been an unprecedented increase in the presence of renewable energies in electricity systems. Considering its benefits, not only in reducing greenhouse gas emissions from energy generation and consumption but also in reducing external dependence on imports of fossil fuels, their promotion has become a policy priority for governments all over the world (Mir-Artigues et al., 2015). In December 2008, the European Union (EU) adopted its Energy and Climate package, a framework where specific objectives in terms of overall share of energy from renewable sources (RES), GHG emissions reduction (compared to 1990) and energy efficiency were established. With regards to renewable energies, an ambitious target has been set. For 2020, a 20% share of renewable energy sources in final energy consumption has to be achieved. A direct consequence of this objective is that renewable energy sources (RES-E) in electricity generation are expected to expand from 20.3% of electricity output in 2010, to around 33% in 2020, in order to meet the objective set by the European Commission.

This promotion of renewable energy has had a predictable impact on energy market prices, the relationship between RES-E deployment and wholesale and retail electricity price being a current area of interest for researchers (Ciarreta et al., 2014; Costa-Campi and Trujillo-Baute, 2015; Edenhofer et al., 2013; Gelabert et al., 2011; Sensfuß et al., 2008). In general terms, consumers finally pay for support for renewable electricity in their electricity bills. Through the access tariffs the money to finance the burden associated with the promotion of RES-E promotion schemes is raised. At the same time, RES-E generation with priority of dispatch on the wholesale market displaces and reduces the demand for conventional electricity – with higher variable costs -. The substitution of conventional generation plants by RES generation therefore reduces the wholesale marginal price (merit order effect). The combined final impact on consumers of both effects depends on whether the reduction in the wholesale electricity market offsets the increase in final price due to RES-E support mechanisms.

Nevertheless RES-E deployment involves other interactions that may affect final electricity prices. The growth in RES-E during recent years largely reflects the expansion of two main sources, namely, wind and solar power. In the EU the quantity of electricity generated from wind turbines has increased more than five-fold since 2002 (Eurostat, 2014), and the growth in electricity generated from solar power has been even more dramatic, rising from just 0.3 TWh in 2002 to reach 71 TWh in 2012. These changes in the energy mix present profound implications for many aspects of power system operation and control (IEA, 2009; Pérez-Arriaga and Batlle, 2012) due to the nature of both wind and solar technologies. Wind and solar photovoltaic (PV) generation are both intermittent technologies, which means that energy output coming from these sources is variable over time and non-fully predictable.

A high penetration of generation from variable renewable sources (VRES-E) imposes additional flexibility requirements on System Operators (SO) in guaranteeing instantaneous equilibrium between demand and supply (Ela et al., 2014; Frunt, 2011; Glachant and Finon, 2010; Haas et al., 2013; Hirth and Ziegenhagen, 2015; Hirth et al., 2015; Vandezande et al., 2010). The variability of renewable generation requires that the power system be operated with a high degree of flexibility, so as to keep pace with the fluctuating net load, defined at each instant as the difference between total energy consumption and total variable renewable production. The application of these flexibility requirements can affect final prices and the costs of renewable market integration, such as balancing costs, need to be considered to compute the economic impacts of an increasing penetration of variable VRES-E on electricity markets. Due to this limited predictability and variability of VRES-E generation, SO might be required to provide significantly higher volumes of these ancillary services than in the past implying additional costs.

In this regard, drawing on real data for the Spanish power market for the period 1 January 2011 to 31 December 2014, the present paper aims to contribute to a better understanding of these economic consequences by evaluating the impact of VRES-E generation on balancing market requirements and costs. In this analysis, we disentangle the economic effect caused by the variability of the effect caused by uncertainty. In terms of system operation both intermittent characteristics are relevant, but given that even with perfect VRES-E generation forecasting, the variability of wind and solar PV output introduce additional system flexibility requirements. Variability and non-fully predictability stress the need for an appropriate number of reserve power plants with flexible dispatch capable of providing the necessary stability and ancillary services to deal with problems of electricity market balance. At the same time, given that the integration of variable generation in a power system non-only depends on both properties of intermittent generation, but also on the power system characteristics into which VRES-E is integrated, the analysis will take system characteristics in terms of flexibility and electricity demand into account. Although power system reliability and resource adequacy are complex elements of market operations and the RES integration cost is influenced by multiple factors, in this paper we examine individually the size of the impact of each attribute of the intermittent generation.

Although this study is applied to Spain the results are of general interest for other countries where the renewable promotion it is at early stages and VRES-E penetration is lower. In this sense, over the last decade Spain had become a leader country with respect to the introduction of renewable energies. The rapid development of renewables in Spain was a direct outcome of national energy policies including regulatory changes focused on facilitating the grid integration of RES-E production and economic and financial incentives[1]. This policy has encouraged, besides the country's great renewable potential itself, investment in renewable energy technologies resulting in an increase in the RES-E installed capacity. With 50,481 MW - including hydro - at the end of 2014 – Spain had occupied a privileged worldwide position in terms of RES-E installed capacity. In terms of output, Spanish RES-E generation has grown from 26 TWh in 2000 to 111 TWh in 2014, when it represented 42.8% of total electricity demand. Among the different RES-E generation technologies, wind and solar PV represented 52% of total RES-E production in 2014. The relevance of both technologies, characterised by their intermittency, presents important system operation implications.

In this way, the results based on one of the countries, within the EU, with the highest renewable power capacities, and one of the most significant wind and solar power generation penetration provides useful insight to other countries. Furthermore, Spain also makes a relevant case study because of the isolated nature of its electricity system, with low interconnection capacity with neighbouring countries (France,

[1] Spain basically followed the "feed-in-tariff" (FIT) policy approach based on the determination of a long-term fixed price for RES-E production or fixed premium tariffs paid on top of the spot market price for electricity.

Portugal, Morocco and Andorra). This represents additional challenges when integrating electricity generation from variable renewable electricity sources.

Even though variability and non-fully predictability need not be a barrier to increased renewable energy deployment, at high levels of VRES-E market penetration a careful economic analysis of the implications in terms of system operation is required. A strong presence of intermittent renewable generation is changing the way power systems are operated and controlled. In this paper we contribute to this analysis by exploring the relationship between the operational costs of the electricity systems, the variability and uncertainty of VRES-E generation and the flexibility requirements of the complementary system necessary to balance the power system.

The remainder of this paper is structured as follows. Variables, empirical strategy, model specification and the data used are detailed in Section 2. Estimation results are presented in Section 3. The paper ends with a final section summarising research conclusions and presenting policy and policy implications.

2. DATA AND EMPIRICAL STRATEGY

As has been pointed out in the previous section, the electrical system has to be in permanent equilibrium. For this purpose, balancing power (regulating and frequency-control power) is used to quickly restore the supply-demand balance in systems after active power imbalances arise. Adjustment services managed by the SO are responsible for adapting hourly production programmes resulting from the day-ahead market to the requirements of demand and supply deviations in real time, thus guaranteeing the above-mentioned balance and meeting the conditions of quality and safety required for the supply of electric power. In the process of programming the generation, the operation of the system is focused on three fundamental aspects: a) the resolution of technical restrictions identified in the programming resulting from the day-ahead and intraday markets, and from the operation itself in real-time; b) the management of the system adjustment services corresponding to the complementary services of frequency and voltage regulation and control of the transmission network; and c) the deviation management process as an essential way of guaranteeing the balance between production and demand, ensuring the availability at all times of the required regulatory reserves.

System adjustment services make it possible to guarantee the permanent equilibrium of the electricity system contracting the active and reactive power reserves necessary to ensure the reliable and safe operation of the electrical system, but implies higher system costs and at the end higher final electricity prices for the consumers. The impact of the cost of these adjustment services on final prices is presented in Table 1 together with the rest of the components that integrate final electricity prices.

(Insert Table 1 here)

Although, power system reliability and resource adequacy are complex elements of market operations where final cost is influenced by multiple factors, in this paper we isolate and quantify the economic impact of the deployment of variable renewable energies on adjustment services. In this regard, from market data for Spain for the period comprised between 1st January 2011 and 31st December 2014, the cost of system adjustment services - technical constraints, secondary control, tertiary control, power reserve, deviation management and real-time constraints – is used as the dependent variable in the econometric estimation. This adjustment (or operational) cost has been defined as a price spread between the final electricity price and the price after the last intraday market session. Deviations between scheduled and measured energy after the intraday market are addressed through market procedures, including secondary reserve, tertiary reserve and the imbalance management process. The costs associated with these balancing markets are captured by this spread, which measures the additional costs for delivering one MWh of electricity on top of the day-ahead and intraday price. When obtaining this spread, capacity payments[2] are not considered. In other words, the adjustment cost results from the aggregate of overall system adjustment services managed by the SO – technical and real-time constraints, power reserve, secondary and tertiary control band and deviation management process services.

Taking into account the above considerations, and bearing in mind that the final electricity price is the sum of the different prices and costs associated with each of the markets that integrate the power system, the adjustment service cost (ASC) is obtained as shown in the following equation (with all variables expressed in €/MWh):

$$ASC_t = FP_t - DAMP_t - IMP_t - CP_t \qquad (1)$$

being:

ASC_t:	Adjustment service cost
FP_t:	Electricity final price
$DAMP_t$:	Day-ahead market price
IMP_t:	Intraday markets price
CP_t:	Capacity payments

[2] Capacity payments are the regulated payments to finance the medium and long-term power capacity services supplied by the generation facilities to the electricity system.

When assessing the determinant factors behind power system balancing costs the following variables are used:

VRES-E generation (VRES G)

The introduction of large amounts of variable and uncertain power sources, such as wind power, into the electricity grid presents a number of challenges for system operations. One issue involves the uncertainty associated with scheduling power that wind will supply in future timeframes. Although wind and solar photovoltaic power output may display some daily and seasonal characteristics and the forecast models have improved significantly over the past years, electricity generation from wind and solar sources is uncertain, implying unforeseen deviations from scheduled electricity programs. The greater range of variability experienced, even by aggregations of wind and solar PV power plants, also adds to the difficulty of forecasting output on the day-ahead timescale. VRES-E generation imbalances imply economic costs given that their correction entails the use of balancing power. Deviations between scheduled and consumed electricity are addressed through ancillary services based, in most instances, on market procedures, such as secondary and tertiary reserves, and the imbalance management process, and so there is a direct relationship between the size of the deviation and the cost incurred by the system in resolving it. Therefore, there is a direct relationship between VRES-E generation and the expected total costs in terms of adjustment services.

Given that, as shown in Figure 1, wind and solar PV production seem to be negatively correlated presenting different –potentially complementary- diurnal patterns with different periods of high (low) output, the variable VRES-E generation (*VRES G*) is defined on an aggregate basis. In this way, *VRES G* is defined as the sum of hourly wind and solar PV production scheduled in the day-ahead market[3] (in relative terms over hourly demand).

(Insert Figure 1 here)

VRES-E ramp (VRES R)

Even with perfect forecasting for VRES-E generation, ceteris paribus the consequence for electricity systems of increasing variability in the RES-E output constitutes an additional source of stress on system operation (Huber et al., 2014; NERC, 2010; Ulbig and Anderson, 2012). In this sense, some studies (Eurelectric, 2010) consider that another relevant factor besides the power production profile is power ramps or gradients over different time horizons. Whilst traditional variability of demand or load has always required a certain amount of flexibility, power ramps will introduce a step change in the way electrical systems are operated. Sudden hourly VRES-E schedules imply additional operational requirements to the system considering that sufficient generation has to be committed to accommodate these variations. In this paper, variable renewable generation ramps (*VRES R*) have been defined as the change of power in a given time interval – in our case from hour to hour -. Changes in operational requirements due to *VRES R* normally take place in the morning and early evening hours. As illustrated in Figure 1, the ramp up in solar generation in the mid-morning and the solar ramp down in early evening can increase the energy regulation requirements of the system. At the same time solar and wind ramps do not necessarily happen at the same moment. In many hours, the combination of solar and wind resources can lessen operational requirements because solar resources are ramping up when wind resources are ramping down, and vice-versa, the aggregated variability of

[3] Hourly wind and solar PV generation scheduled in the Daily Base Operating Program (PDBF by its acronym in Spanish)

both technologies together being less than each are individually. Given that and considering that the geographic diversity and dispersion of wind and solar PV output reduces aggregate variability over large geographic areas, the ramp variable has been defined on an aggregate basis. As in the case of the variable corresponding to renewable generation, the gradients of renewable production are expressed in relative terms on the hourly demand, and in absolute terms.

Conventional generation flexibility (CGF)

In order to maintain reliable power system operation as variable energy resources provide a larger proportion of our electric energy supply, sufficient system flexibility will be required. Operational flexibility is an important property of electric power systems. The term flexibility is widely used in the context of power systems although at times without a proper definition. The role of operational flexibility for the transition from existing power systems, many of them based on fossil fuels, towards power systems effectively accommodating high shares of VRES-E has been widely recognized. Integrating large shares of VRES-E generation, in particular wind and solar PV, can lead to a sharp increase in flexibility requirements for the complementary power system (Huber et al., 2014). In the case of Spain, this complementary or conventional system is mainly composed of combined cycle, coal, fuel oil and gas generation, and these have to balance the fluctuations of variable generation.

Categorizing different types of operational flexibility constitutes a complex question (Ulbig and Andersson, 2012) due to the existence of different flexibility metrics. In this paper, as the flexibility strongly depends on the total contribution of wind and solar energy to hourly electricity consumption and load evolution, *Conventional*

Generation Flexibility (CGF) from flexible sources is defined in terms of power portfolio connected to the system able to provide balancing energy to the system. Nuclear and hydroelectric generation are considered to be inflexible given that these generation technologies are currently operated in a base-load mode.

The presence of intermittent generation in power systems with priority of dispatch together with a large quantity of inflexible conventional generation alters and reduces the net load to be satisfied with flexible generation able to start up and shut down generation as the system requires. Sudden and massive requests for power, in terms of power ramps, create new requirements for conventional generators. In this paper, we have defined conventional generation from flexible sources (*CGF*) as final production from flexible technologies - coal, fuel oil, and gas (open and combined cycles) -.

Given that these flexible generation technologies have different characteristics – costs and time required to start, ramping limits – which determine their capacity to start up quickly and increase their production when the system requires, the importance of the combined cycles in terms of system operation will be assessed independently (*CCGT* variable) from the rest of flexible generation technologies (*OTHERS* variable). Combined cycle technology is one of the most important back-up technology able to adjust its generation to provide power when it is most needed (Eurelectric, 2010). With more than 25 TW of installed capacity – 24.8% of total peninsular installed capacity, as at 31^{st} December 2014-, CCGTs are normally particularly suited to adjusting their output to net load-following operations. At present, CCGT allows SO to deal with both upward and downward VRES-E ramps that may reach 2,000 MWh from hour to hour.

Regarding the econometric approach, using hourly market data for Spain over the period comprised between the 1st January 2011 and the 30th December 2014, a time series regression model controlling for seasonality was constructed. The econometric estimation uses the average weighted cost of system adjustment services (*ASC*) as the dependent variable. This variable, obtained as a price spread, includes the economic cost associated with all adjustment services - technical constraints, secondary control, tertiary control, power reserve, deviation management and real-time constraints -. VRES-E output (*VRES G*), VRES-E gradients or ramps (*VRES R*) and conventional power generation (*CGF*) are used as the main explanatory variables.

In addition, as in other electricity market price studies, we have introduced an autoregressive component to capture the dynamic effects on the adjustment costs. Two additional variables were introduced as control variables. First, to control for consumption patterns in peak and off-peak demand hours we introduced a temporary variable (*Peak Demand (PD)).* As electricity demand varies through the day, this dummy variable (=1 if a peak demand hour) was introduced in the specification of the model in order to address aspects related to seasonality. Second, as VRES-E generation is not the only source of variation in a power system, a second control variable was introduced to control for other possible power imbalances. The demand for electricity, or load, also varies, and the power system was designed to handle that uncertainty. After intraday market gate closure, SO have to adjust the resulting program to any demand and supply deviations from that scheduled. The required balancing energy to handle electricity deviations coming after intraday gate closure *(Real Demand Adjustment (RDA))* was included in the model specification. As in the case of the rest of variables, *RDA* is expressed in relative terms on hourly demand. Table 2 presents the descriptive statistics of the variables used.

(Insert Table 2 here)

Before presenting the time series regression models constructed for the analysis of the impact of RES-E integration on adjustment costs, it should be pointed out that a stationary time series analysis was carried out. We performed two tests. First, the augmented Dickey-Fuller (ADF) test (Dickey and Fuller, 1979) under the null hypothesis of a unit root, and second the Kwiatkowski-Phillips-Schmidt-Shin (KPSS) tests (Kwiatkowski, et al., 1992) under the null hypothesis of stationarity. Both tests, reported in table 3, confirm that the series are stationary in logarithms, so we estimate the models using all series in logarithms.

(Insert Table 3 here)

With all the above considerations, the model specification is defined in the following equation:

$$ASC_t = \alpha_0 + \alpha_1 ASC_{t-1} + \alpha_2 VRES\ G_t + \alpha_3 VRES\ R_t + \alpha_4 CGF_t + \alpha_5 RDA_t + \alpha_5 PD_t + \varepsilon_t \qquad (2)$$

Based on the information from the summary statistics of the dependent variable – specifically the high standard deviation and the maximum value- and the graphical representation of this series (see Figure 2) in which extreme values are observable even in logs, we are suspicious about the existence of outliers.

(Insert Figure 2 here)

A deep outlier analysis was carried out to confirm the existence of extreme values. We used the blocked adaptive computationally efficient outlier nominators (BACON) algorithm proposed by Billor et al. (2000) and further developed by Weber (2010) to detect outliers in our multivariate data. The results for the BACON test (see Appendix) confirm the existence of extreme values of the observable variables.

The presence of the outliers, which has been confirmed as valid observations, might drive to biased results. In the context of this study, either by ignoring or excluding the outliers might distort the resultant effects from renewable generation on system costs. On the one hand by ignoring their presence and performing the estimations through Ordinary Least Square (OLS), would assign the same weights to the extreme observations and leads to different coefficients than the actual relation between the variables. On the other hand, by acknowledging the problem but using robust regression to exclude the outliers could also affect the magnitude of the estimated effects. For these reasons, in this paper, we perform the estimation of Eq.(2) using quantile regression on the median. The quantile approach is not as sensitive as the least squares approach to outliers because it does not give much weight to them (at the median it gives symmetric weights to positive and negative residuals), but at the same time, unlike robust estimation, quantile estimation does not sacrifice observations with relevant information[4].

Our methodological choice, although properly tackling the complexity of this study, it is based on the principle of simplicity. First, we could apply more sophisticated modelling technics (for instance as the error correction models, which would allow us to observe the speed at which the ASC returns to the equilibrium) that would be beyond the direct goal of this research. Second, given that the variables are stationary in logs, a simple autoregressive linear regression model it is sufficient to perform the

[4] As a further robustness test we have estimated Eq. (2) using robust regression. The results of the two stages robust estimations, not reported but available upon request, are consistent with those of quantile IV (reported below) in terms of sing and significance of coefficients. As expected from the exclusion of outliers and from the use of the mean when performing robust regression, the value of coefficients differs from those of the quantile regression, although the magnitudes are similar.

analysis. Finally, provided that the series content outliers we need to consider, a more sophisticated technique would complicated further the study.

As in the least squares estimation of dynamic models, it is evident that the unobserved initial values of the dynamic process also induce a bias in the context of quantile regression. The existence of unobserved initial values of the dynamic process arises from the fact that the history of the process begins prior to the first period of observed data. Given that the exogeneity it is defined from the concept of predetermined values, the existence of unobserved initial values implies that the classical liner model assumption of strict exogeneity it is violated and OLS estimates of the coefficients become biased. The same it is true for quantile estimates in an autoregressive linear model, the coefficients must absorb the effects of each lagged error, and the model residuals no longer represent true changes in the dynamic process. Hence, it become necessary to correct this bias in order to obtain coefficients capturing more accurately relation between the variables. Instrumental variable methods are able to produce consistent estimators for dynamic data models that are independent of the initial conditions. These estimators are based on the idea that lagged (or lagged differences of) regressors are correlated with the included regressor but are uncorrelated with the error terms. Thus, valid instruments are available from inside the model and these can be used to estimate the parameters of interest employing instrumental variable methods. In this paper the construction of instruments is carried out using values of the dependent variable lagged two periods and the lag of the exogenous variables[5], which are all independent of ε_t, to perform estimations using the instrumental variable quantile regression method.

[5] As an additional robustness test we have estimated Eq. (2) by quantile IV using a different transformation of the variables, i.e. the square of variables, as instruments. The results, not reported but available upon request, are highly consistent with those obtained with the lag variables as instruments.

3. RESULTS AND DISCUSSION

In order to evaluate the effects of VRES-E generation *(VRES G)*, VRES-E variability *(VRES R)*, and conventional generation flexibility *(CGF)* on adjustment costs *(ASC)* we performed five sets of estimations based on Eq. (2) as presented in the previous section with different groups of control variables. We first estimated the impact of VRES-E generation on ASC including only the additional controls *(RDA and PD*), these results are reported in column (1) of Table 4. In the second set of estimations - column (2) - we also included the ramp or gradient of VRES-E *(VRES R)* to test if along with the penetration of VRES-E there is also a relevant intensity of sudden changes in consecutive hours. In the third set of estimations –column (3) – we introduce the penetration of aggregated conventional flexibility *(CGF)* in order to evaluate its potential in reducing adjustment costs. Finally, in the last two sets of estimations we evaluate the contribution of the most flexible technology *(CCGT)*, by first introducing only CCGT –column (4) – and then adding the other sources of flexibility *(OTHERS)* –column (5).

From a system management perspective, several factors, coming from both supply and demand variables, might cause active power imbalances in electricity systems. From the supply side, the results of the estimations support a significant and positive effect of VRES-E generation on adjustment services costs. Short-run elasticity of VRES E ranges between 0.01 and 0.05 depending on the group of control variables, being consistently around 0.02 – 0.03 with the full set of controls clearly showing that renewable generation from variable sources such as wind and solar PV introduce additional variability and uncertainty into the power system. In order to maintain reliable power system operation as variable energy resources provide a larger proportion of our electric energy supply, sufficient system flexibility will be required exerting a positive and relevant effect on the adjustment cost.

(Insert Table 4 here)

Although there are different links between VRES-E and its associated balancing requirements[6] (Hirth and Ziegenhagen, 2013), we disentangle the economic effect coming from variability than from non-fully predictability in VRES-E output. In this regard, when the ramp or gradient of VRES-E *(VRES R)* is included in the estimation – column (2) – it is demonstrate that sudden changes in VRES-E output also exert a positive and significant effect on adjustment costs. Although not so relevant as VRES G, short-run elasticity of VRES G ranges consistently around 0.01.

In terms of system operation, these results are showing up that, even with perfect forecast tools, the variability of renewable generation requires that the power system should be operated with a high degree of flexibility. Although, variability is not new to power systems, which must constantly balance the supply and variable demand for electricity and face all kinds of contingencies (IEA, 2009, 2011a, 2011b), large shares of intermittent renewable generation in supply imply additional pressure on power systems. Renewable variability requires increased flexibility where aspects such as the availability of flexible capacities within the electricity generation mix, interconnection capacity, storage - e.g. pumped-hydro plants - or improved load control and management empowered by smart grids acquire more relevance.

[6] There is a multitude of names for the different services available to restore the supply-demand balance in power systems (see Hirth and Ziegenhagen, 2013 and Rivero et al., 2011 for a comprehensive comparison of European balancing markets). This heterogeneity could be hampering the comparative analysis of balancing services across Europe. Considering that European transmission system operators are using the term "operational reserves" (ENTSO-E, 2012), in this paper we use the concept "operational costs" in a broad sense when referring to the costs associated with the provision of these services.

Therefore, the results confirm that, along with the penetration of VRES-E, adjustment services costs increase with the intensity of VRES-E generation changes in consecutive hours, the ramp (VRES R). Although initially a higher intensity of this effect, might be expected the magnitude of the parameter VRES R seems to be capturing that the interaction between wind and photovoltaic ramping hours are complementing each other, and hence exerting a relatively reduced effect on the system adjustment services costs (see Figure 3).

(Insert Figure 3 here)

VRES-E production is determined by weather conditions and cannot be adjusted in the same way as the output of dispatchable conventional power plants (Hirth et al., 2015). As can be seen in Figure 3, on the one hand, solar photovoltaic generation is characterised by a diurnal pattern, where peak production occurs in the middle of the day (around 14.00). On the other hand wind generation is more variable over time and is mostly explained by fluctuations in wind conditions – mainly speed -. Although wind power output may display some daily and seasonal characteristics, it follows much less regular patterns than does load. Although in the period comprised between 2011 and 2014 the yearly average of wind generation for each hour fluctuated between 4.9 and 7.1 TWh, with an average hourly production of 6 TWh. Wind power output tends to be higher during the night period followed by a downward ramp in wind production in the morning and a later increase from noon.

Furthermore, variable generation is not necessarily correlated with load with the consequent implications that this has in countries with relatively limited storage capacity such as Spain. Depending on the time scale considered, the load profile presents different daily, weekly, monthly, seasonal or even yearly patterns. Figure 4 shows how Spanish electrical demand varies throughout the day with peaks of demand at noon and in the early hours of the night.

(Insert Figure 4 here)

Even though several factors are behind, VRES-E integration costs strongly depend on power system characteristics. The evolution of installed intermittent capacity constitutes a relevant factor but not the only one involved. From the point of view of power system operation and management, a scenario of low penetration of renewable energies in the generation mix is not the same as a scenario where renewable power is one of the main generating sources, as is the case in Spain. Sudden hourly VRES-E schedules or deviations from scheduled energy imply additional operational requirements to the system considering that enough generation has to be committed to accommodate these variations. In this regard, the availability of flexible conventional generation connected to the system constitutes a relevant question when addressing the question of the explanatory factors behind the evolution of the adjustment services. This issue is evaluated in our model when the availability of flexible generation sources is incorporated as explanatory factor of the adjustment costs – estimations presented in columns (3) to (5) -. When considering all the flexible generation together, from an aggregated perspective, the short-run elasticity is 0.03 – see column (3). When CCGT, as the most flexible technology, is separated from the rest *(OTHERS),* the results show that CCGT elasticity is 0.02 and for the rest it is 0.003 – see columns (4) and (5). Therefore, the results confirm that conventional flexible generation decreases adjustment services costs and that the CCGT cost saving effect is greater than it is in the case of other technologies.

In general terms, these results confirm the relevance of other aspects when explaining the system adjustment costs. The estimations support a significant and positive effect of VRES-E penetration on balancing costs. However, as we demonstrate in this paper, the cost associated with the integration of renewable energies depends on other aspects. Questions such as VRES-E output measured in terms of power ramps over different time horizons or the availability of flexible conventional generation connected to the system are also relevant.

The results for the additional control variables, *RDA* and *PD*, are consistent across the different sets of estimations and in line with expectations. Regarding the *RDA*, our results confirm that demand adjustments are considered to be a factor increasing adjustment services costs. Likewise, the peak hour control captures the hourly consumption pattern during the day, and shows that during peak hours adjustment services costs are higher. Both control variables are significant, and in the context of this study, are important for guaranteeing the proper estimation of the parameters of interest.

In order to provide additional insights, Table 5 summarizes the relevant long-run elasticity from the analysis performed. On the one hand, we observe that if there were an increase of 10% in *VRES-E* penetration with the same flexible generation, in the long run the system would face an increase in the adjustment cost of 2.2%. On the other hand, ceteris paribus, if the penetration of aggregated flexible generation were increased by 10% a saving would be made of 2.9% on adjustment services costs. These results highlight the importance of the interaction – counterbalance effects - between *VRES G* and *CGF* from the system perspective, and consequently on the adjustment services costs.

(Insert Table 5 here)

Finally, a highly interesting result comes to light with the comparison of the long run elasticity between generation from CCGT and the other sources of flexibility. While a 10% increase in CCGT penetration would lead to a decrease of 1.4% in adjustment services costs, an equivalent increase of the other conventional sources would imply savings of only 0.2%.

4. CONCLUSIONS AND POLICY IMPLICATIONS

At the end of 2013, renewable energy sources covered approximately 14.7% of Spanish final energy consumption. Given that by the year 2020 Spain is required to meet the European target of covering 20% of the energy demand using renewable sources, it is expected an increase of VRES-E are expected in order to comply with the approved European objectives. The power system integration of this VRES-E output impacts, as we demonstrate in this paper, on system operation, the final cost depending on multiple factors. A critical issue in power system operation is the amount of balancing and operating reserves that will be needed to keep the power system functioning securely and efficiently (Holttinen et al., 2011; Pérez-Arriaga and Batlle, 2012) and this study evaluates the nexus between power system balancing costs evolution and the increasing presence of intermittent renewable production.

The penetration of intermittent generation – especially wind and photovoltaic power – in Spain has developed to levels that were unthinkable a decade ago. Technical improvements coming from both VRES-E power producers (fault-ride-through capabilities, visibility and controllability of VRES-E power, reactive power control…) and the system operators (specific control centre for RES energies, forecasting tools…) are behind this success in quantitative terms. Nevertheless, given that VRES-E market integration is crucial, a comparative quantification of the overall system-related costs and benefits of the increase in VRES-E is required.

Although the factors that might cause power imbalances in relation to the daily scheduled programs are varied and of different nature[7], the integration of variable and uncertain renewable generation sources increases the flexibility needed to maintain the load-generation balance. From a system perspective, integrating non-manageable generation constitutes a challenging task. Aspects such as low availability, lack of correlation between VRES-E generation and energy load, and absence of firmness in generation programs, among others, impose new power balance challenges given that electricity systems should be constantly adjusting to fluctuations in demand and supply. Therefore, power generation coming from variable renewable sources can affect the design of balancing markets in different ways. First, the variability and uncertainty of wind and solar PV energy increases requirements for various ancillary services, affecting the scheduling and pricing of those services. Second, VRES-E impacts strongly depend on system conditions (demand situation, importance of renewable geneation in electricity programs, scheduling regime of the other conventional generation facilities, mix of generation technologies, existing flexible generation…), which make the demand for ancillary services difficult to generalize across timescales and systems.

[7] From a system management perspective, several factors coming from both supply and demand variables might cause active power imbalances in an electricity system. From the supply side, aspects such as unplanned contingencies in the conventional and renewable generation capacity or in the interconnection capacity, or variability and forecast errors of VRES-E generation due to its intermittent nature increase the need for balancing power (Huber et al., 2014). From the demand side, aspects such as load forecast errors have a similar effect.

In addition, the variability and uncertainty associated with VRES-E generation implies real-time deviations in renewable power generation, explained by its non-full predictability, affect daily markets and result in higher balancing costs and greater fluctuation in the reserve requirements. At the same time, the variability of renewable electricity production, with an availability ratio - production in relation to the installed capacity - ranging between 5% and 70%, implies the need for flexible power capable of covering those moments when renewable generation is not available. As expected, the results point toward a significant effect of VRES-E integration on system costs. According to our estimates, both VRES-E attributes – uncertainty and variability – exert a positive and significant effect on adjustment costs, their respective intensities being statistically different, always higher in the case of the variable responsible for capturing the uncertainty derived from the non-full predictability of VRES-E generation. These results highlight the relevance of forecast errors when explaining integration costs. Deviations between scheduled energy and real time demand are addressed through ancillary services, which are mostly based on market procedures, such as secondary and tertiary reserves and imbalance management processes. Therefore, there is a direct relationship between the size of the deviation and the cost to the system of solving it. At the same time, power ramps introduce a step change in the way electrical systems are operated, exerting a positive impact on system costs. Variability implies additional operational requirements to the power system considering that additional generation has to be committed to accommodate these variations.

From the broader perspective of energy policy and sector regulation, a key question when evaluating the evolution of RES integration refers to the availability of sufficient operational flexibility. As demonstrated, this additional flexibility, a necessary precondition for the grid integration of large shares of VRES-E power, is provided by conventional generation. The system integration of VRES-E generation requires flexible technologies able to modulate their production to provide coverage for demand. In an isolated country such as Spain, with low cross-border interconnection capacity, the availability of flexible plants acquires increasing importance. Power plants able to work on a part-time operational schedule and ready to provide the upward/downward power are required by the system. Among these flexible technologies, the results indicate the importance of combined cycles. CCGT allows the SO to deal with sudden up and down VRES ramps at the most competitive cost in comparison to other flexible technologies. In Spain, this last issue is of great importance. Although the system has more than 25 TW of installed capacity using combined cycles, the fall in electricity demand as well as a growing share of the renewable in the demand means that a very small part of this power is connected to the network when the system requires it. The low availability of mid-merit power technologies able to change their output dynamically in contrast to baseload conventional technologies, as we demonstrate in this paper, has its economic consequences in terms of adjustment costs.

Minimising total system costs at high shares of VRES-E requires a strategic approach to adapting and transforming the energy system as a whole. To meet this goal, all countries where VRES-E is becoming a mainstream part of the electricity mix should make better use of existing flexibility by optimising system and market operations. Sending the correct signals to participants, to encourage them to look for the optimum technical solutions, entails an in-depth knowledge of cost drivers as provided by this paper. Success in adapting the power system lies in analyses able to provide clearer insights into the costs and impacts associated with incorporating renewable energy into electricity networks.

ACKNOWLEDGEMENTS

We would like to thank the two anonymous referees for helpful comments and suggestions. We are also grateful for the support of the Generalitat de Catalunya SGR project 2014-SGR-531 and from the Chair on Energy and Environmental Sustainability (University of Barcelona and FUNSEAM).

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APPENDIX

From the summary statistics (see Table 2 and Figure 2 in the main text) and from a basic examination of the series some concerns arise regarding the possible presence of extreme values for some of the observed variables in logarithms. To analyse the outliers in the series, a three-step approach was followed: in the first step we confirm the existence of outliers, in the second we identify the most relevant outliers, and in the third step we check their validity in the original dataset.

We used the blocked adaptive computationally efficient outlier nominators (BACON) algorithm proposed by Billor et al. (2000) and further developed by Weber (2010) to detect outliers in our multivariate data. The algorithm starts from the identification of an initial subset of m outlier-free observations out of a sample of n observations and over the p variables of the model, where the subset size m is given by the product of the number of variables p and a parameter x chosen to determine the percentile $(1 - x)$ of the chi-squared distribution to be used as a threshold to separate outliers from non-outliers. After an iterative process (see Weber, 2010) those observations excluded from the final basic subset are nominated as outliers, whereas those inside the final basic subset are non-outliers. We chose six percentiles $(1 - x)$ to perform the test for the four models. The results of the BACON test (Table A1) confirm the existence of extreme values of the observable variables in all five models with different thresholds.

(Insert Table A1 here)

To identify the most important outliers we draw on the approaches proposed by Fox (1991) and Bohernstedt and Knoke (2002). Thus, for the model with the highest level of information (model 5) the top ten observations with the highest standardized residual (five positive and five negative) were selected. In Table A2 we present the standardized residuals, standardized DF Betas and Cook's distance values for the selected observations.

(Insert Table A2 here)

The standardized residual is the residual divided by its standard error. When the distribution of the residuals is approximately normal, 95% of the standardized residuals should fall between -2 and +2. If many of the residuals fall outside of + or – 2, then they can be considered unusual, which is the case for all the selected observations. The standardized DF Betas measure the extent to which an observation has affected the estimate of a regression. Values larger than $2/\sqrt{n}$ in absolute value (0.0101 in our data) are considered highly influential; this condition is met for all the selected observations. Finally, the Cook's distance measures the aggregate impact of each observation on the group of regression coefficients, as well as on the group of fitted values. Values larger than $4/n$ (0.0001 in our data) are considered highly influential; this is the case for all the selected observations.

These analyses lead us to the conclusion that the extreme values for some of the observed variables are likely to have a highly influential impact on the estimates. Clearly, estimations performed using least square methods that include the outliers would result in biased outcomes. We proceeded to confirm the validity of the identified outliers by contrasting their values with those in the original data set and with a Spanish Power System Operator specialist. As a result, we can confirm that the outliers are real observations and therefore relevant for the empirical study.